HREA-HECO-RT-1-IR-1

On page 9 (lines 1 to 3), you state the "independent implementation of DG/CHP results in loss of revenue to the utility." See also your comments on page 11 (lines 17 to 18). Is this really the case, when the utility is experiencing load growth, such as we are now in the islands? Specifically, as the load grows and new generation is needed, aren't we really talking about revenue opportunities, and not revenue losses?

HECO Response:

Non-utility DG/CHP installed by or for an existing customer facility will result in a loss of revenue to the utility. Both utility and non-utility DG/CHP can be implemented to meet new load growth. In such a case, non-utility DG/CHP results in a loss of potential utility revenues.

HREA-HECO-RT-1-IR-2

On page 9 (lines 17 to 19), are you suggesting that because the "Companies have used DG sited at substations to address transmission and generation capacity requirements," that this makes it right for the Companies to do CHP? Please explain.

HECO Response:

The testimony is relative to CHP, as a form of DG, being a natural step in the evolution of the Companies' services. The reference to substation-sited DG reinforces the point that the utility has direct experience and expertise with the application, installation, and operation of DG.

HREA-HECO-RT-1-IR-3

On page 10 (lines 10- to 12), please provide evidence of your assertion that "the general trend has been for CHP equipment vendors and energy service companies to move away from the model of owning equipment at a customer site."

HECO Response:

The testimony is based on direct discussion with several DG developers including Hess Microgen and Cummins West. Hess Microgen is now focusing on equipment sales rather than owning and operating CHP installations. Cummins West is actively involved in developing CHP projects but does not offer a Cummins-owned option.

HREA-HECO-RT-1-IR-4

On page 11 (lines 3 to 8), you claim that the Companies' economic analysis shows a positive net present benefit for all the Companies. HREA notes that the approximate net benefit over 20 years is $2.262M (about $113K/yr) for Oahu. However, we also note that the annual benefits are negative in 11 of the first 12 years of HECO's proposed program. With the $250K annual program cost element, which is not included in HECO's analysis, the annual average benefits would then be a NEGATIVE $137K. So how can you claim there is a net positive benefit to Oahu's ratepayers?

HECO Response:

The basis of the Companies' economic analysis is over a 20 year period, which is consistent with the terms of the CHP Agreements of the Companies' proposed CHP Program. Over the life of the proposed CHP Program, there will be a net positive benefit to ratepayers.

As work has progressed on HECO's third integrated resource plan (IRP-3), the CHP Program economic analysis has been reviewed and corrections have been made to specific items. The original analysis filed with Docket No. 03-0366 understated the revenues associated with the utility CHP Program. A mathematical error was made resulting in the understatement of thermal fees and facility fees from the year 2009 forward. Instead of using the annual value of such revenues, the amount used was the value of such revenues for one month. Correction of these revenues will increase the net benefit of the CHP Program, on a net present value ("NPV") basis, by nearly $8.5 million. After working with Hess and other vendors, HECO has also concluded that the heat rate used for the initial analyses was too optimistic. A more accurate heat rate for the generic unit would be approximately 10% higher resulting in higher CHP system operating costs. Updating the analysis for the more accurate heat rate information would decrease the net benefit of the CHP Program, on an NPV basis, by about $0.2 million. With the aforementioned mathematical error correction and heat rate modification, the NPV benefit of installing CHP systems (under the CHP Program parameters) would be about $10.6 million.

In addition, adding CHP systems now will be even more beneficial than was estimated in the CHP Program analysis due to the increasing demand impacts on the HECO system as noted in HECO's March 31, 2004 Adequacy of Supply letter to the Commission. CHP capacity that can be brought into service between the present time and 2009 should have a significantly higher avoided capacity value than indicated in the original economic analysis for the CHP Program. This is because the CHP Program analysis assumed that there would be no capacity deferral benefit before 2009, as additional capacity was not expected to be needed until 2009.

HREA-HECO-RT-1-IR-5

On page 14 (lines 3 to 11), your statements appear to be a restatement of your response to HREA-HECO-T-3-IR-1. Please provide specific examples to support your claim that third party CHP systems may be of substandard design or construction, and may be operated by third parties that lack adequate operating and maintenance training and experience. HREA also observes that you are implying that the Companies' CHP systems are superior. Please provide evidence that this is the case.

HECO Response:

An example is the cogeneration system installed by a third-party at the Pohai Nani Good Samaritan Retirement Community. As described in HECO's Annual Report on Status of Establishing Interconnection Agreements for Distributed Generation Customers, filed January 30, 2004 in Docket No. 02-0051, the unit was installed in September 2002, but was not operated for over a year due to safety concerns. Pohai Nani has addressed the concerns and the unit was placed into operation in November 2003. Two other examples of CHP installations which experienced problems as noted on page 2 of HECO T-4, were the University of Nations and Hualalai Regency systems.

HECO is not stating that its CHP systems will be superior, rather the testimony states that some, but not all, CHP systems installed by third-parties may be of substandard design or construction. Other non-utility CHP systems can be designed, operated, and maintained to provide adequate service to host CHP customers. In addition, CHP systems that are installed, operated and maintained by the utilities, will benefit from the Companies' expertise because the utilities core business is power generation and the utilities have substantial power generation experience.

HREA-HECO-RT-1-IR-6

On page 15 (line 7) to page 16 (line 9) and also page 17 (lines 5 to 9), could not the system requirements/specifications that you propose for utility-owned CHP be made part of an non-utility CHP interconnection agreement that would make the non-utility CHP provider accountable to the utility for providing the same requirements/ specifications? Please explain your response.

HECO Response:

The primary objectives of the interconnection agreement process for distributed generators are to ensure safety, reliability, power quality, protection of utility and customer equipment, and to support restoration of power on the utility system. (See Appendix I to HECO Rule 14.H.) The system operation and maintenance requirements/specifications described in HECO-RT-1 are not necessarily intended for such purposes and therefore may be inappropriate for inclusion in an interconnection agreement. It is not known if the non-utility CHP providers would be agreeable to having to meet such system operation and maintenance requirements/specifications. If the owner of a non-utility CHP system were willing to agree to any such requirements/specifications, including allowing the utility to control the operation and maintenance of the CHP system, the terms of that agreement would likely need to be detailed in a separate contract between the utility and CHP system owner.

HREA-HECO-RT-1-IR-7

As a follow-up to HREA-HECO-RT-1-IR-6, you indicate that HECO would use synchronous generators, which are quite a bit more expensive than induction generators. HREA notes that HECO's CHP tariff filing (Docket No. 03-0366) assumes that the utility will ONLY install induction generators (and if the customer wants synchronous generators, the customer is supposed to bear the cost differential). Given this change from induction to synchronous generators, are you planning to revise Exhibit H to the tariff filing to show synchronous generator costs?

HECO Response:

HECO does not understand the basis for HREA's reference to use of induction generators by the utility. The utilities' proposed CHP Program assumed the use of synchronous generators. In Exhibit E of the Companies' proposed Schedule CHP tariff, included in the CHP Program application, Docket No. 03-0366, proposed standard form CHP contracts are provided for each company. Synchronous generators are specified – see, for example, Exhibit E, page 27 of 99.

HREA-HECO-RT-1-IR-8

As a follow-up to HREA-HECO-RT-1-IR-6, you indicate HECO will install four control modes, which are not currently provided on any of the third party installed systems in Hawaii. Are the added costs for these modes included in Exhibit H?

HECO Response:

As described in the testimony, the Companies are finalizing their preferred CHP unit dispatch parameters, therefore the specific control modes described have not been individually costed out. However, the Companies' CHP system cost estimates did assume the use of control systems that provide remote utility-operability of the CHP systems. The Companies maintain that these cost estimates are reasonable.

HREA-HECO-RT-1-IR-9

On page 18 (line 12), your reference to page 9 of HREA's direct testimony appears to be incorrect. Please identify the correct page number, or clarify your comment so that we can respond.

HECO Response:

On page 9, line 13 of HREA-T-1, HREA lists as a barrier to a competitive market the following:

"Buyers may be uncertain about new Sellers."

HREA-HECO-RT-1-IR-10

On page 18 (lines 18 to 22), you refer to the Companies' discussions with customers. HREA believes it would be valuable to this docket, if the Companies would identify the customers referenced above, and make them available for discussion. Are the Companies willing to do that? Please explain your response.

<u>HECO Response:</u>

The Companies have already identified a number of customers with whom it has had discussions concerning CHP systems. HECO RT-1, page 40, cited the execution of CHP Agreements with Pacific Allied and the Sheraton Keauhou Resort. Exhibit HECO-105 to HECO T-1 lists Outrigger Hotels, the Mauna Kea Beach and Hapuna Beach Prince hotels, Hawaiian Building Maintenance, and the Grand Wailea Resort that provided comments to the Companies on utility-owned and-operated CHP systems. In addition, the Companies' response to LOL-SOP-IR-82 on page 20 listed several other customers with whom the Companies have had discussions and developed letters of intent. The written comments to the Companies on utility-owned and operated CHP systems represent such companies' positions on the subject.

HREA-HECO-RT-1-IR-11

On page 22 (lines 10 to 16) and page 24 (lines 7) to page 25 (line 4), regarding HECO's perception of what makes for a competitive market, do you support use of conventional approaches, such as the Herfindahl-Hirschman market index, to characterize the nature of the anticipated CHP market? Specifically, in the Rebuttal Testimony of Jim Lazar on behalf of the County of Maui (Reference County of Maui Exhibit RT-2), Mr. Lazar has calculated the Herfindahl-Hirschman index for HECO's forecasted market share of CHP systems to be in excess of 5,300, where any number over 1,800 is considered to be "Highly Concentrated." Please explain position, given that Mr. Lazar's analysis contradicts your claim that "a competitive market will exist even if the utility owns and operates a majority of the CHP installations."

HECO Response:

HECO's position on the Hawaii CHP market takes into account the varying roles and objectives that equipment manufacturers and energy services companies have when considering their participation in the CHP market. Yet, the Herfindahl-Hirschman market index may not account for these varying roles and objectives. For example, although equipment manufacturers may have the dual capability of developing their own CHP system projects, they may actually have as their primary business objective the sale of CHP equipment, not ownership of the CHP systems. Under the proposed HECO CHP Program, these equipment manufacturers/CHP developers would sell equipment to HECO and would achieve their objective, as would HECO. Yet the Herfindahl-Hirschman market index might consider this as an undesirable result from the perspective of the equipment manufacturers/CHP developers simply because the CHP systems would be owned by HECO.

Ultimately, HECO believes that the market should be judged on the practical and realistic manner in which the utility, DG developers, equipment providers, and CHP host customers will co-exist to best serve the interests of Hawaii's energy consumers, including those that are participating and those that are not participating in CHP.

HREA-HECO-RT-1-IR-12

On page 22 (line 20) Page 23 (line 9), have there been any instances where HECO has offered balance of central plant equipment and services? If so, please explain the apparent change in HECO's philosophy on this issue.

HECO Response:

As described on page 27 of HECO T-1, the Companies did consider offering balance of central plant equipment and services along with CHP systems when customers asked if the utility would do so. The Companies ultimately determined that it would not be appropriate to go beyond the CHP system offering, for the reasons stated on lines 17 to 24 of HECO T-1 page 27.

HREA-HECO-RT-1-IR-13

On page 26 (lines 12 – 17), why would bidding every small CHP project not be efficient?

<u>HECO Response:</u>

Compared to larger projects, smaller CHP system projects will tend to allow more standardization in design and installation, and bidding every small project may not be worthwhile as long as a good cost database is established. Overall costs will be lower, meaning there is less potential benefit to going through a full bid process for the smaller CHP systems. There will also tend to be greater numbers of smaller CHP system projects, making a full bid process inefficient.

HREA-HECO-RT-1-IR-14

On page 28 (line 22) to page 29 (line 6), you have recognized that there have been complaints about the process to obtain an interconnection agreement and suggest that that the Rule 14.H will subject all Parties to the same requirements and process. Given that, what would be a reasonable amount of time be for a third party to receive an approved interconnection agreement from HECO, assuming the third party has submitted a "complete" application for an interconnection agreement? Also, please elaborate as necessary on what would constitute a "complete" application.

HECO Response:

The timeframe for completing an interconnection agreement will depend on several factors such as whether a detailed technical study of the interconnection proposal is necessary, the timeframe for the customer (or third party) and HECO to work together to resolve any discrepancies in the single-line diagram, relay list, trip scheme and settings, and three-line diagram (required for generating facilities ≥ 30kW), and the timeframe for the customer (or third party) to complete Exhibit B of the Standard Interconnection Agreement (Facility Owned by the Customer or Third Party Owner). Due to the case-by-case specifics of the interconnection of a DG unit, it is not possible to provide a generic timeframe for the completion of an interconnection agreement because elements of the interconnection process are controlled by the customer, not by HECO. The timeframes for the steps in the interconnection agreement process which HECO has responsibility are identified in Appendix III of Rule 14H.

A complete application will include a completed Exhibit A of the Standard Interconnection Agreement (Description of Customer's Generating Facility), a single-line diagram, relay list, trip scheme and settings, and three-line diagram (for generating facilities ≥ 30kW).

HREA-HECO-RT-1-IR-15

On page 32 (lines 16 - 21), would you agree that HECO is assuming less risk than third parties, knowing that HECO's costs will likely be approved for recovery by the PUC, whereas third parties don't have this type of "safety net?"

HECO Response:

No. HECO does not agree with HREA's claim that "HECO's costs will likely be approved for recovery by the PUC". There is no "safety net" associated with recovery of HECO's costs associated with utility-owned and-operated CHP systems.

HREA-HECO-RT-1-IR-16

On page 32 (line 22) to page 33 (line 3), HREA suggests that this is an aspect of how Rule 14.H, which was not developed in a voluntary consensus manner, can negatively impact an industry entity. Please comment if you disagree.

HECO Response:

The Companies disagree and stand by their position that Rule 14.H. was properly developed in consultation with the Consumer Advocate, and approved by the Commission, taking into account the interests of potential DG customers and other utility customers.

HREA-HECO-RT-1-IR-17

On page 35 (lines 10 to 13), you state that the "Prior to the commencement of this docket; the Companies had not formulated a position as to whether a CHP System or a distributed generator owned by a third-party should be regulated by the Commission, except in the case of nonfossil-fuel generating facilities." HREA would like to note that MECO previously acquiesced to a non-utility diesel CHP plant for Maui Land & Pine that also served customers in the Kaahumanu shopping center, and the PUC approved it. Thus, it would appear that the Companies have formulated a position. Please comment if you disagree.

HECO Response:

MECO is familiar with the circumstances under which Maui Land & Pineapple Company ("MLPCO") supplied electricity to its own shopping center (and to the tenants of the shopping center) from diesel engine generators (i.e., fossil-fuel fired DG units). However, that case falls under the category of customer-owned generation, not third-party owned generators.

MLPCO owned the Kaahumanu Shopping Center. The shopping center is adjacent to a pineapple cannery owned by Maui Pineapple Company, Ltd. ("MPCO"), a subsidiary of MLPCO. MPCO generated electric power for use by the pineapple cannery plant and the shopping center (including common areas and the tenants). The shopping center areas provided electricity from the MPCO generators were disconnected from MECO's system. All of the facilities were located on private properties. Tenants of the shopping center received power, and were charged for the power based on their relative use (in the same way they would have been if MECO supplied power to the shopping center on a master metered basis).

A number of cases have held that if a service, which would ordinarily be considered to be public utility service, is carried on as incidental to the main purpose of a business (which is not the provision of public utility service), then the incidental business will not be considered to be public utility service. Cases citing this principle often have dealt with a fact situation where a company's main business was the leasing of space to the tenants of a shopping center or an apartment building, and its incidental business was the provision of electricity to the tenants. See Re Maui Electric Co., Docket No. 6514, Decision and Order No. 10517 (February 5, 1990); Annot., 75 ALR 3d 1204 (1977), “Landlord Supplying Gas, Water, or Similar Facility to Tenant as Subject to Utility Regulation”.

HREA-HECO-RT-1-IR-18

On page 39 (lines 9 to 18) and page 40 (lines 5 to 14), you have claimed that numerous customers see value in the Companies' proposed CHP program, and cite two example (Pacific Allied Products and the Sheraton Keauhou Resort). HREA believes it would be valuable to this docket, if the Companies would make these two customers available for discussion. Are the Companies willing to do that? Please explain your response.

<u>HECO Response:</u>

The basis for attributing support of the Companies' proposed CHP Program to Pacific Allied and Sheraton Keauhou is the fact that both customers executed CHP Agreements with the utility to develop CHP systems under the parameters of the proposed CHP Program. However, it is not within the purview of the Companies to "make these two customers available for discussion".

HREA-HECO-RT-1-IR-19

On page 43 (lines 1 to 17), you have raised some important definition issues. Specifically, you suggest that "DSM Programs are designed to influence the use of energy." HREA would agree, and would clarify that definition by saying DSM Programs are designed to conserve energy and to use energy more efficiently, both of which serve to reduce energy demand. Would you agree?

<u>HECO Response:</u>

No. HREA's clarification appears to limit the definition of DSM programs to those that "are designed to conserve energy and use energy more efficiently". HREA's clarification does not take into consideration other types of DSM programs, such as load management programs and educational programs. HECO further defines DSM programs in HECO RT-1, pages 42 through 48.

HREA-HECO-RT-1-IR-20

As a follow-up to HREA-HECO-RT-1-IR-18, HREA observes that there are already DSM Programs that supply energy, i.e., the solar hot water programs for residential and commercial customers. HREA believes all DER measures, including measures to supply energy such as DG, which are implemented on the customer's side of the meter, all qualify as DSM measures, whether they are currently recognized and promoted as DSM programs. Another example would be net metering, which is not currently recognized as a DSM program. Would you agree?

HECO Response:

No, HECO does not agree that all DER measures that are implemented on the customer's side of the meter qualify as DSM measures.

The IRP Framework approved by the Commission in Decision and Order No. 11630, dated May 22, 1992, in Docket No. 6617, does not use the location of the measure (in relation to the meter) to define whether a measure is demand-side or supply-side. Rather, as indicated in RT-1, page 43, lines 1-17, the IRP Framework defines DSM Programs as ". . . programs designed to influence utility customer uses . . .", and Supply-side programs as ". . . programs designed to supply power."

Solar water heaters are DSM measures because they are passive collectors (rather than suppliers) of solar energy, are backed up by electric resistance heating elements, and serve to reduce the use of energy. (See HECO RT-1, page 47, line 20, to page 48, line 21.) A customer's participation in net energy metering implies that the customer may at times supply energy from a renewable resource into the grid. Under IRP Framework definitions renewable energy is a supply-side option. (See the IRP Framework, Section I. Definitions.) See also HECO's response to PUC-IR-5.

HREA-HECO-RT-1-IR-21

On page 43 (line 20) to page 44 (line 9), are not there certain DSM measures, such as automated load management and efficiency systems, that are operated and maintained by third party Energy Service Companies (ESCOs)?

HECO Response:

Third party ESCOs may operate and maintain customer-owned HVAC systems at the customer's discretion. Whether operated and maintained by a third-party ESCO or by the customer, HVAC systems are DSM measures because they reduce the customer's energy use without supplying energy.

HREA-HECO-RT-1-IR-22

On page 44 (line 17) to page 46 (line 9), HREA thanks you for discussing the differences between solar hot water systems and CHP systems, especially in terms of level of energy output (certainly residential hot water systems are lower output than the CHPs envisioned by HECO, but higher temperature solar systems may soon come to the market, and some of these will be CHPs) and numbers (there are currently many more residential hot water systems that perhaps anyone envisions for CHP, unless you consider the possibility of residential CHPs, which may soon come to the market). Thus, HREA observes that the differences are primarily in scale rather than type. Both solar and CHP systems are options that a customer can elect to choose reduce his electrical demand from the utility. So, why would it be impractical for the Companies to own thousands of solar systems? For example, the Companies most likely own thousands of utility poles and transformers.

HECO Response:

It would be impractical for the Companies to own thousands of solar systems because, among other reasons, they are installed on privately-owned property and to maintain them the Companies would need to obtain the property owners' permission to gain access to the panels on the roof and water storage tanks in garages and closets. In contrast, access to utility poles and transformers less problematic because they are located in utility rights-of-way.

The difference between CHP and residential hot water systems is more than scale. The major difference is that CHP is a supply-side measure, while solar hot water systems are demand-side measures. (See HECO RT-1, page 43, lines 1-17.)

HREA-HECO-RT-2-IR-1

On page 2 (line 24), since Renewable Hawaii, Inc. is a HECO company, please clarify how it is a non-regulated subsidiary.

HECO Response:

Renewable Hawaii, Inc. ("RHI") was incorporated on December 19, 2002 and Bylaws were adopted by the corporation on the same day. Pursuant to the Articles of Incorporation, RHI has a Board of Directors and Officers assigned by the Board of Directors. RHI is a non-regulated independent subsidiary of Hawaiian Electric Company, Inc. ("HECO"), separate from the utility and does not engage in regulated utility activities. As such, it is not under the auspices of the State of Hawaii Public Utility Commission. Accounting practices and conflict screens are in place to ensure an arms-length relationship between HECO and RHI.

RHI will review and evaluate the proposals. If the proposals are deemed feasible and viable for RHI passive, equity investments, then RHI will seek appropriate agreements with the proposers. After the proposers have signed agreements with RHI, the proposers will obtain the appropriate permits and approvals from various government agencies and enter into negotiations for a PPA with the utility, which is subject to PUC approval (see HECO RT-2, pages 4-6).

HREA-HECO-RT-3-IR-1

On page 2 (line 4), please explain the generating system reliability goal of 4.5 years per day, and contrast this goal with other potential reliability goals, such as Mean Time Between Failure (MTBF) and percentage of time without failures (i.e., 99%, 99.9%, 99.99%, etc.).

HECO Response:

The generating system reliability threshold of 4.5 years per day is based on a Loss of Load Probability ("LOLP") calculation as applied to a generating system consisting of multiple generating units, with each having a certain reliability level. LOLP is the probability that, for a given system of generating units, the available capacity in any given day is not sufficient to satisfy the peak demand on the system due to the unavailability of units resulting from planned or unplanned outages.

Typically, LOLP is expressed as the number of days in a year (or days per year) that the available capacity will not be sufficient to meet the peak demand on the system. HECO represents generating system reliability as the inverse of LOLP. Hence, the units of measure in HECO's reliability guideline are years per day. The reliability values then represent the probable amount of time that will elapse before an event occurs where available capacity will not be sufficient to meet the peak demand.

For example, in the LOLP calculation where the result is expressed as the number of days in a year, a determination may be made for a given system that the LOLP is 0.22 days per year. This means that in a given year, there may be 0.22 days in which the peak demand will not be satisfied. This also means that the probability is (0.22 days) / (365 days), or 0.0006 (or one chance in 1,660) that the peak demand will not be satisfied. Under HECO's convention, the reliability of the generating system is the inverse of the LOLP value, or 1 / (0.22), or 4.5 years per day. This means that there is a probability of experiencing one event in a 4.5 year period that the peak demand will not be satisfied.

HECO adopted the convention of representing generating system reliability as the inverse of LOLP because larger numbers would mean higher reliability. For example, a system with a reliability level of 10 years per day is more reliable than one with a reliability level of 8 years per day because the former system has a probability of experiencing a generating system-related outage once every ten years while the latter system has a probability of experiencing a generating system-related outage once every eight years.

LOLP is a function of the number of generating units on the system, the normal outupt capability of each unit, the planned maintenance schedule for each unit, the effective force outage rate (or "EFOR") of each unit, and the peak demand that the generating system needs to serve in each day. EFOR, in essence, is the percentage of time that a generating unit is not available for service because of unplanned, or "forced," outages or deratings.

An example of the LOLP calculation is provided on pages 3 to 6 of this response.

The Mean Time Between Failure ("MTBF") as referred to in HREA's question, is the average time expected between failures of a repairable component over some specified time period. MTBF is typically applied to individual pieces of equipment, such as pumps, fans or motors, or individual components, such as bearings or seals, rather than to entire generating units or entire generating systems. Higher MTBF values equate to better reliability.

With respect to "percentage of time without failures (i.e., 99%, 99.9%, 99.99%, etc.)" as referred to in HREA's question, the values are an indication of "availability" or the percentage of time that particular equipment or components are available for use. The concept may also be applied to other things, such as computer software or even electrical service. An availability level of 99.99% means that something is available for use 99.99% of the time, or that the unavailable time, or "down time" is about 53 minutes in an entire year.

Sample Calculation of Loss of Load Probability

The Loss of Load Probability (LOLP) calculation quantifies the probability that a particular generating system will be unable to serve a given demand. The calculation uses the following inputs:

- normal capability rating (or reserve rating in HELCO's case) of each generating unit;
- equivalent force outage rate (EFOR) for each generating unit;
- maintenance schedule for each generating unit and
- peak demand in each day.

The calculation treats the forced outages of generating units as random and independent events.

To illustrate the calculation, consider a system consisting of three generating units (for simplicity, maintenance schedules are not considered):

Table 1
Characteristics of Generating Units in a Hypothetical System

	Capacity, MW	Equivalent Forced Outage Rate	In-Service Rate (1 – EFOR)
Unit A	50	0.05	0.95
Unit B	100	0.07	0.93
Unit C	200	0.10	0.90
Total	350		

Table 2
All Possible Forced Outage States on the System

Units on Forced Outage			MW on Forced Outage	Units in Service			Probability of Particular State	
A	B	C		A	B	C		
None			0	X	X	X	0.95 x 0.93 x 0.90 =	0.7952
X			50		X	X	0.05 x 0.93 x 0.90 =	0.0419
	X		100	X		X	0.95 x 0.07 x 0.90 =	0.0599
		X	200	X	X		0.95 x 0.93 x 0.10 =	0.0884
X	X		150			X	0.05 x 0.07 x 0.90 =	0.0032
X		X	250		X		0.05 x 0.93 x 0.10 =	0.0047
	X	X	300	X			0.95 x 0.07 x 0.10 =	0.0067
X	X	X	350	None			0.05 x 0.07 x 0.10 =	0.0004
							Sum =	1.0000

Suppose a determination must be made of the probability that a 220 MW peak demand could not be served with the given system on a particular day. First, all states in which there are less than 220 MW in service must be identified. Then the probabilities of those states must be summed.

Table 3
Probability that a 220 MW Peak Demand Could Not Be Served

MW on Forced Outage	MW in Service	Probability of State	220 MW in Service?	Probability
0	350	0.7952	Yes	
50	300	0.0419	Yes	
100	250	0.0599	Yes	
200	150	0.0884	No	0.0884
150	200	0.0032	No	0.0032
250	100	0.0047	No	0.0047
300	50	0.0067	No	0.0067
350	0	0.0004	No	0.0004
		1.0000	Total =	0.1032

Therefore, there is a probability of 0.1032, or about a 10% chance, that a 220 MW peak demand on a particular day could not be served by this particular system.

The above example illustrates the calculation for a particular day. The resulting probability value can be interpreted to mean 0.1032 days per day that a 220 MW demand could not be served. The concept can be expanded to cover a series of days.

Suppose a series of days, each with a particular peak demand is considered, as shown in Table 4. The calculation would be as follows:

Table 4
Probability that Peak Demand Could Not Be Served

Day	Peak Demand, MW	Probability of State
Sunday	140	0.0047 + 0.0067 + 0.0004 = 0.0117
Monday	280	0.0599 + 0.0884 + 0.0032 + 0.0047 + 0.0067 + 0.0004 = 0.1630
Tuesday	240	0.0884 + 0.0032 + 0.0047 + 0.0067 + 0.0004 = 0.1032
Wednesday	220	0.0884 + 0.0032 + 0.0047 + 0.0067 + 0.0004 = 0.1032
Thursday	260	0.0599 + 0.0884 + 0.0032 + 0.0047 + 0.0067 + 0.0004 = 0.1630
Friday	290	0.0599 + 0.0884 + 0.0032 + 0.0047 + 0.0067 + 0.0004 = 0.1630
Saturday	130	0.0047 + 0.0067 + 0.0004 = 0.0117
	Total =	0.7186

The calculation indicates there is probability of about 0.72 days over a period of seven days (or 0.72 days per week) that the demand will not be served. This is about equal to 0.72 / 7 = 0.103 or about a 10% chance over the seven-day period.

If the peak demand for every day of an entire year is known, then the calculation can be performed for the entire year. The result would be expressed in terms of days per year.

HECO uses a program, called PREL, to perform this type of LOLP calculations for its system. PREL is a module of PMONTH, which is a production simulation computer model used by HECO, HELCO and MECO, and which was developed by PPlus Corporation.

Determining LOLP is calculation-intensive. Since each generating unit has two possible states (available or unavailable), then 2^N states must be evaluated, where N is the number of generating units on the system. There are 19 firm capacity generating units on the HECO system. Therefore, 2^{19} or 524,288 states must be evaluate for each day in the year to determine the LOLP for that year. With the computing power available on today's personal computers, this does not pose a problem.

Typical values resulting from the LOLP calculations are fractions of a day per year. HECO long ago adopted a convention of taking the inverse of the result such that the units would be in days per year. This is primarily because greater reliability values resulted in higher values so that people could more easily understand the reliability numbers in terms of "bigger is better." For example, a system may have an LOLP of 10.0 years per day under a given set of conditions and an LOLP of 5.0 years per day under another set of conditions. The system with an LOLP of 10.0 years per day is more reliable than the system with an LOLP of 5.0 years per day.

HREA-HECO-RT-3-IR-2

On page 2 (line 25) to page 3 (line 3), please provide more details regarding the number and capacity of generators that were off-line, and comment on how the generator downtimes compare with and/or impacts the reliability goal stated above.

HECO Response:

On October 12 and October 13, 2004, the following generating units were unavailable:

Unit	Reason for unavailability
Waiau 3	Generator electric problem (unavailable from 2103 hours 10/12/04 to 1204 hours 10/13/04)
Waiau 8	Scheduled maintenance
Waiau 9	Turbine problem
Kalaeloa	Superheater tube leak on CT-2 (unavailable from 2103 hours 10/12/04 to 1705 hours 10/13/04)
H-POWER	Scheduled maintenance to boiler #2

As explained in HECO's response to HREA-HECO-RT-3-IR-1, generating system reliability is a function of the number of generating units on the system, the normal output capability of each unit, the planned maintenance schedule for each unit, the effective force outage rate (or "EFOR") of each unit, and the peak demand that the generating system needs to serve in each day. All of the unit unavailabilities listed above impact the actual generating system reliability. Any time a unit is not available for service, the Loss of Load Probability increases. In other words, whenever any generating unit is not available, there is a higher probability that the system demand may not be satisfied due to an unexpected, or "forced" outage of the remaining generating units. The fact that five generating units were simultaneously unavailable greatly increased the probability that the system demand may not be satisfied.

HREA-HECO-RT-3-IR-3

On page 5 (lines 22 to 24), wouldn't it be more correct if the sentence read; "the additional firm capacity will help address the reserve margin situation, but will not offset the need for capacity offered by potential CHP systems?"

HECO Response:

The referenced section of the rebuttal testimony states, "The additional firm capacity will help address the reserve margin situation, but will not offset the need for the capacity offered by utility owned CHP systems." Either this statement or the one stated in HREA's question above is correct.

HREA-HECO-RT-3-IR-4

On page 11 (lines 13 to 23), would it be possible to modify the existing base integration analysis to estimate the impacts of the utility CHP program on non-participants? If so, do you have an estimate of how much the modifications would cost?

HECO Response:

In the rebuttal testimony in HECO RT-3, page 11, lines 19 to 22, HECO indicated that "The revenue impact analysis cannot be performed during the base integration analysis because the dynamic optimization computer model used for the integration analysis does not have a means to evaluate this. This evaluation must be done outside of the model." It would not be possible to modify, as HREA suggests, the existing base integration analysis to estimate the impacts of the utility CHP program on non-participants and complete the IRP integration analysis within the given time constraints. (HECO is targetting filing of its IRP-3 report in mid-2005, and the integration analysis must be completed near the end of 2004.)

Implied in HREA's question is that a modification to the dynamic optimization computer model could enable the base integration analysis to include an estimate of the impacts of the utility CHP program on non-participants. HECO does not have access to the software vendor's computer code so HECO would be unable create its own program subroutine to perform the calculations within the model. Even if HECO did have access to the software vendor's computer code, HECO does not have the expertise, resources or approval of the software vendor to modify the computer software. While it may be possible for the software vendor to develop a program subroutine that could incorporate the revenue impacts into the optimization, it would probably take many months to develop such a subroutine because of the complexity of both the existing software and the revenue impact analysis. HECO already has the tools to perform both tasks (plan optimizations and revenue impact analysis). They are just not integrated into a single model. HECO does not have a cost estimate of how much the modifications would cost.

Therefore, performing the revenue impact analysis outside of the model in a supplemental analysis is the most time- and cost-efficient means to accomplish the task.

HREA-HECO-RT-4-IR-1

On page 2 (lines 5 to 10) and several other places in your testimony (pages 5, 6, 7, 9, and 10), you discuss the difficulty of doing long-term analysis of transmission and distribution analysis to support planning for CHP in IRP. Why not just focus on short-term analysis to support the 5-year action plans for each IRP?

HECO Response:

HECO RT-4, page 5, line 3 through page 6, line 18 explained the difficulties of incorporating CHP, which included the need to determine the location for CHP projects and the uncertainty involved in locating CHP over a long-term period of 20 years. However, HECO RT-4, page 6, line 20 through page 8, line 10 explained how the Companies have worked with these difficulties and incorporated distributed generation (in which CHP is a form of distributed generation) into HELCO's and MECO's IRP-2 analysis and how HECO will incorporate distributed generation into the HECO IRP-3, which is in process. In addition, HECO RT-4, page 11, line 14 through line 21, explains that distribution impacts will not be incorporated into the IRP-3 process for reasons explained in HECO RT-4, page 9, line 22 through page 11, line 13, however, the Distribution Planning process is consistent with the IRP planning process and takes into consideration load reduction (which CHP can contribute towards), DG at Substations and distribution capacity solutions on a project specific basis.

HREA-HECO-RT-4-IR-2

On page 12 (lines 18 to 23), you discuss the practical issues with DG. Would you agree that central generation (CG) has the same practical issues, and, in general, resolving these issues is easier for DG than for CG? Please explain your answer.

HECO Response:

Both central station generation and DG have practical issues that need to be resolved before each can be installed. In concept, if considering the practical issues of a single DG installation and a central station generator, it would likely be easier to resolve the transmission-related issues with the single DG unit compared to the central station generator. HECO RT-4, pages 12-13, however, is explaining the practical issues of using substantial amounts of DG and combined heat and power ("CHP") to mitigate transmission constraints, and is not comparing it with the installation of new central station capacity. Installing additional transmission capacity will also have practical issues which will need to be addressed.

Theoretically, the use of DG and CHP can have an impact on the transmission system and HECO attempts to capture some of the impacts through evaluating DG and CHP on a system-wide basis, as explained in HECO RT-4, pages 7-8 and 14, in order to deal with some of the practical issues which cause uncertainties with DG and CHP, as explained in HECO RT-4, pages 13-14. In the studies that the Companies have conducted which considered DG as an option for addressing criteria violations and/or reliability concerns above what has already been placed into the load forecast, the conclusions of the analysis show that DG is not a viable solution. Refer to HECO T-4, pages 10-13.

HREA-HECO-RT-4-IR-3

Are there any other analytical models available today or under development which could enhance HECO's current ability to model transmission and distribution issues to support planning for CHP in IRP?

HECO Response:

HECO objects to this information request as it is overly broad and unduly burdensome in that it could be construed to ask for information concerning all "analytical models available today or under development". Without waiving any objections, HECO provides the following response. HECO's current analytical models are adequate to model transmission and distribution ("T&D") systems and are currently used to identify issues with the T&D system(s). The Power Technologies Institute (PTI) Power System Simulator for Engineering ("PSS/E") model, which HECO uses, is a model used widely in transmission planning on the mainland and around the world. The PSS/E model can also be used to model CHP systems on the system.

HREA-HECO-RT-5-IR-1

On page 4 (lines 14 to 24), HREA believes that the price signals should be improved by removing the class cross-subsidies. Do you agree? Please explain your answer.

HECO Response:

HECO believes that removing class cross-subsidies would improve price signals. Please see the Company's direct testimony HECO T-5, pages 11 to 15, wherein the Company identified cross subsidies and intra-class subsidies as important rate design issues in the efficient deployment of DG.

HREA-HECO-RT-5-IR-2

On page 9 (lines 7 to 17), when designing stand-by service rates, would it not be appropriate to take into account the services that the DG facility is providing to the utility, e.g., capacity at no charge to the utility? Please explain your answer.

<u>HECO Response:</u>

The utility rates are based on recovering the utility's costs of providing service. The design of standby service rates will be based on the utility's costs of providing standby service. There are 3 basic steps in designing rates as stated in HECO T-5, page 2, lines 1-3. The 3 steps include: (1) determination of the utility's total revenue requirements or the utility's total costs of providing service; (2) determination of each class' cost responsibility or allocation of the utility's total cost of providing service; and (3) rate design which is simply translating the class' cost of service into rates or prices. The services provided by the DG facility, if any and if significant enough, could impact the utility's cost of providing service (step 1 above) – and therefore, is indirectly taken into account. To the extent that the data on the DG facilities' operation characteristics as well as the standby load profile is available, and depending on DG market size, such information could impact the determination of the cost of providing standby service or the allocation of costs (step 2 above). The third step in the rate design process translates the class' cost into price or rates on the basis of some measurable variable, such as the customer's standby kW, which is normally based on the rated capacity of the DG facility that the Company is standing by. To the extent that data is available and/or measurable, the unit basis, e.g., determination of the billing standby kW, may take into account to the extent possible and reasonable, services that the DG facility will or could provide.

HREA-HECO-RT-5-IR-3

On page 10 (lines 8 to 13), you discuss the stipulated standby rate level on HELCO's standby service rider (Rider A). What was the basis for the apportionment among generation (at 20%), transmission (at 52%) and distribution demand (100%) costs?

HECO Response:

The apportionment among generation (at 20%), transmission (at 52%) and distribution demand (100%) costs used to determine HELCO's standby service rider (Rider A) is based on the settlement agreement between HELCO and the Consumer Advocate ("CA") in HELCO's Docket No. 99-0207. The basis of the agreement between HELCO and the CA is discussed in HELCO's Final Standby Service Rider Proposal and Supporting Statement in HELCO's Docket No. 99-0207, which was filed with the PUC on January 24, 2001. The stipulated Rider A was approved by the Commission in its Decision and Order No. 18575, issued on June 1, 2001, in Docket No. 99-0207.

HREA-HECO-RT-5-IR-4

Regarding the discussion on the COM's proposal on inverted rates for the residential class on pages 13 and 14, conceivably removing the class cross-subsidies could totally change this discussion. Do you agree?

<u>HECO Response:</u>

No. HECO does not agree that removing the class cross-subsidies could or would totally change the discussion in HECO RT-5, pages 13 and 14, relating to the COM's proposal on inverted rates for the residential class. HECO stands by the reasons provided in the referenced HECO testimony on why the COM's proposal should be rejected by the Commission. For instance, removing the class cross-subsidies will not make the residential customers the potential users of the distributed generation as defined in this docket. Second, removing the class cross-subsidies will not eliminate nor resolve the impact of the inverted rates to exacerbate the intra-class subsidization within the residential as it would further increase the subsidy from the high users to the low users, since the high users would end-up paying more of the residential fixed costs (e.g., customer-related and demand-related costs) embedded in the energy rates. Third, removing the class cross-subsidies will not change the Commission's factual findings in Docket No. 3874, that inverted rates would result in assisting lower use households and penalizing higher use households, and that household size is an important determinant of power usage, and poverty households tend to have larger household size. Lastly, removing class cross-subsidies does not negate HECO's position that time-of-use rates will provide more accurate price signals for customers to efficiently manage their load, than the COM's proposed inverted rates.

HREA-HECO-RT-5-IR-5

On page 14 (lines 7 to 14), please provide a brief discussion of the demographics of the 160 residential customers participating in the pilot time-of-use rate program.

HECO Response:

The majority (80.5%) of the participants live in single-family dwelling units, and the majority (89.6%) are home owners. The majority (78.6%) of the participants have to 2 to 5 people in their households, and the average household size is 3.1 persons per household – which is larger than Oahu's average household size of 2.95 persons per household reported in 2000 (based on the 2000 Census).

In terms of residential loads, 60% of the participants have air-conditioning load, 49.4% have electric water heaters, and 31.8% have solar water heaters. In terms of energy usage, the program participants appear to have higher usage than the average residential customer. The participants' base average monthly kWh is 667 kWh per month for Option 1 participants, and 848 kWh per month for Option 2 participants – both higher than the average residential usage of 589 kWh per month reported for October 2004 year-to-date.

HREA-HECO-RT-5-IR-6

Also on page 14 (lines 17 to 22), please provide a brief discussion as to whether the current declining block rates for Schedules J and P reflect the actual costs to serve those customers. Specifically, how do the costs go down with increased energy use?

HECO Response:

The design of the declining load factor energy rates for Schedules J and P is discussed in the Companies' direct testimony HECO T-5, beginning on page 10, and is based on these classes' cost of service. As discussed in the referenced testimony, a significant portion of the classes' fixed costs (e.g., demand-related and customer-related costs) are recovered in the energy rates. And the declining energy rates for the load factor blocks is due to recovering more of these fixed costs from the 1st and 2nd load factor blocks. The energy rate for each load factor block recovers all the energy costs for that block plus some of the fixed costs that are not recovered from the customer charge and the energy charge.

HREA-HECO-RT-5A-IR-1

On page 2 (lines 10 to 12), HREA observes that we already have a "partial" rate unbundling in Hawaii. On our monthly residential bills, we see separate charges as follows: customer charge, non-fuel energy, base fuel energy, energy cost adjustment, IRP cost recovery, and sometimes a temporary rate adjustment. If the bills were adjusted to incorporate the breakout that you have suggested on page 6 (i.e., generation, transmission, distribution, ancillary services and retail supply), HREA believes this would provide a valuable educational service to customers. Do you agree? Please explain your answer.

<u>HECO Response:</u>

Some customers may find educational value in further unbundling of rates while other customers may find unbundled rates confusing and a burden. Furthermore, the implementation costs associated with unbundled rates are not trivial. I do not have values for the costs and potential benefits associated with unbundled rates and, therefore, cannot say that the benefits would outweigh the costs. The primary benefit of unbundled rates is in the accommodation of retail competition which does not exist in Hawaii.

HREA-HECO-RT-5A-IR-2

On page 8 (lines 17 to 26), page 11 (lines 2 to 13) and page 13 (line 12) to page 15 (line 6), when designing stand-by service rates, would it not be appropriate to take into account the services that the CHP facility is providing to the utility, e.g., capacity at no charge to the utility? HREA notes that the CHP facility provides capacity by virtue of off-setting the need for utility generators to supply a portion up to the customer's entire load. Furthermore, given that there will be some periods when the CHP facility will be down for maintenance, it is primarily the down periods which coincide with the utility's peak periods that are important. In any case, given that an individual CHP's size will be a small fraction of the utility's capacity and it is not likely that a large number of CHPs will be down at the same time, HREA believes the utility will be able to cover the CHP's normal load with its operational reserve and/or spinning reserve (which is available on Oahu). Please explain your answer.

HECO Response:

As I state in my rebuttal testimony, the full reservation amount is applied to the full cost of transmission and distribution. This is not true for generation capacity where only a portion of the generation costs is applied to the reservation amount. This portion is to reflect the DG customer's investment in generation capacity and its fair share of the costs associated with reserve generation capacity which, in turn, is a cost allocation issue. Absent a detailed analysis of the utility's costs, I cannot tell you exactly what that portion would be. Also see HECO response to HREA-HECO-RT-5-IR-2.

HREA-HECO-RT-5A-IR-3

On page 9 (lines 3 to 4), are you aware of any other jurisdiction in the United States where the utility is allowed to own and rate base customer-sited generation sized so as not to deliver electricity to the grid? HREA believes other jurisdictions treat this is a non-utility function. If utility-owned DG/CHP facilities use fuel more efficiently than central generation, is that a benefit belonging to the customer on whose site the generation is located, so that that customer should get a discount for it, or is that a benefit that belongs to the utility system customers as a whole and should be rolled in to all customer rates and ERAC computations?

HECO Response:

I have not done a detailed search of all state jurisdictions in the U.S., so I cannot answer this question. As I state in my rebuttal testimony, however, I feel that it is appropriate for the utility to own DG facilities. In that testimony I say that the utility-owned DG is viewed as a system-wide resource, therefore, benefits owed to any fuel efficiency belong to the utility system customers.

HREA-HECO-RT-5A-IR-4

On page 9 (line 9) to page 10 (line 6), why have you not mentioned the need for a customer of a utility-owned CHP to pay for stand-by service? Does not the utility have to provide back-up service to this DG customer upon request, just like any other customer?

HECO Response:

The rates paid by this type of customer would already include the costs related to reserve capacity (see HECO RT-5A at 9, lines 13-15), and therefore, to charge for standby service would result in double recovery of costs.

HREA-HECO-RT-5A-IR-5

On pages 13 and 14, how does your proposal for stand-by rates distinguish between those units that go down a lot and make more calls on the system
from those which perform reliably? HREA observes that is why the County of Maui's consultant, Jim Lazar, puts more of the costs in the energy charge.

HECO Response:

Those units that "go down a lot" will pay more because they purchase more energy to cover their needs when their unit is down. The costs related to standby reserve are capacity costs and those capacity costs do not vary with the frequency of the customer's generation outage.

HREA-HECO-RT-5A-IR-6

On page 16 (lines 17 to 21), you state that "Lazar failed to include ancillary service charges in his description of wheeling fees." First, do you agree with CA (page 37 of Herz's rebuttal testimony), that it might be too hard to calculate ancillary service charges? Second, would you agree that a major benefit of unbundling the rates would be to calculate ancillary service charges, whether it be for wheeling fees or for standby rates?

HECO Response:

The correct quote from my testimony is "Mr. Lazar failed to include ancillary service costs in his description of wheeling fees." (emphasis added). Ancillary service costs are primarily related to generation capacity necessary for reserves, regulation service, and other ancillary services. I'm not sure what is meant by "too hard" in the question, but identifying capacity costs can be done. I do not agree that ancillary service charges are a major benefit of unbundling the rates in an environment that has neither wholesale nor retail competition within the system.

HREA-HECO-RT-5A-IR-7

On page 17 (lines 15 to 17), are you aware of any public utility, including municipally-owned and cooperatives, that have implemented any sort of an impact fee on new demand? If so, please provide a brief discussion.

HECO Response:

HECO objects to this information request as it is overly broad and unduly burdensome in that the information request could be construed to request information on any public utility, regardless of the location and type. Without waiving any objections, HECO provides the following response. I am aware of impact fees charged by the Las Cruces (New Mexico) water, wastewater and natural gas municipal utilities. For this utility, the impact fees are more politically determined and are not necessarily consistent with cost causation.

HREA-HECO-RT-5A-IR-8

HREA believes that the price signals should be improved by removing the class cross-subsidies. Do you agree? Please explain your answer.

HECO Response:

In principle I agree with this statement. Please see the response to HREA-HECO-RT-5-IR-1. However, it does not necessarily follow that removal of cross-subsidies will change overall customer demand in a particular direction. Reducing industrial and commercial customer prices and increasing residential rates, for example, could result in an overall increase in the consumption of electricity if industrial and commercial customers are relatively more responsive to the price reduction.

HREA-HECO-RT-5A-IR-9

In the case where the utility owns and operates a CHP, the ratepayers will pay for the effective capacity, e.g., 1 MW. Given that the utility must provide back-up for that 1 MW load, won't the ratepayers be paying for the capacity twice? Please explain your answer.

HECO Response:

No. Reserve generation capacity in the system is only a portion of total generation capacity.